HYDRO ONE INC.
ANNUAL CONSOLIDATED FINANCIAL STATEMENTS

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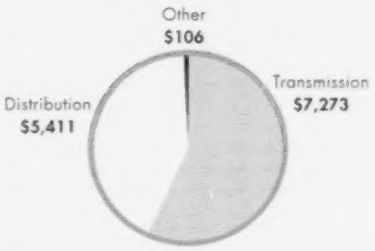
We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2007 and 2006.

OVERVIEW

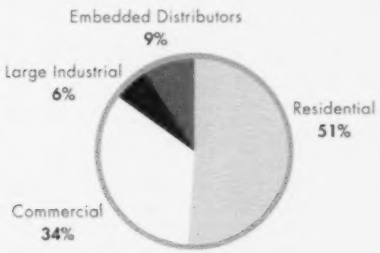
We are wholly owned by the Province of Ontario (the Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). We are the leading electricity transmitter and distributor in Ontario, delivering power safely and reliably to homes and businesses. As stewards of this province's massive and complex transmission and delivery system, our mission is to be an efficient and dynamic transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on the development and retention of our employees and creating shareholder value. In 2007, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from one location, our Ontario Grid Control Centre in Barrie, Ontario. It operates over relatively long distances and links major sources of generation to transmission stations and larger area load centers. In 2007, we earned total transmission revenues of $1,242 million primarily by transmitting approximately 152 TWhs of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MWs and exports of approximately 5,800 MWs of electricity. In terms of assets, our transmission business is our largest business segment, representing approximately 57% of our total assets.



Total Assets
December 31, 2007
(Cdn $ millions)



2007 Distribution Revenues

Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, and 50 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers.

Other

Our other business segment contributed revenues of $31 million in 2007 and has assets of about $106 million, which constitute less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

Our Strategy

In 2007, aligned with retaining and building public confidence and trust, we maintained our strategic focus on our core operations and built upon our accomplishments. Consequently, we have moved closer to achieving our goals to

be recognized by our customers as their best service provider, by our peers as their benchmark for excellence, and by our shareholder as delivering superior value, while striving to attract, develop and retain productive employees.

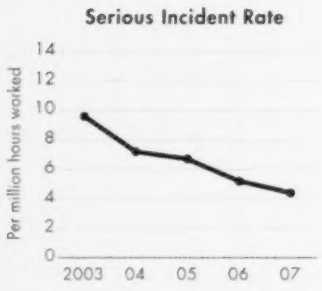
We seek to achieve these goals by continuing to implement the following strategies:

- *Stewardship:* Retain and build the public trust placed in us to ensure the safe, reliable and efficient delivery of electricity.
- *Safety:* Create and maintain an injury-free workplace with a concentrated focus on eliminating serious injury and "near misses" in high potential harm categories of work.
- *Customers:* Become a leading customer-focused company. We intend to maintain our focus and commitment to improving our customers' level of satisfaction. We strive to strengthen relationships with our large and mid-sized customers, acknowledging their commercial requirements. For residential customers, our key focus is on improving the quality of customer services such as billing, call handling, outage management, and meter reading. We also aim to make positive contributions in communities across Ontario through our corporate citizenship programs.
- *Reliability:* Enhance the reliability of our transmission and distribution systems through our productive and cost effective work programs. In transmission, we are proactively developing the system to meet Ontario's power needs. Within distribution, we are focused on reliability while recognizing the challenges in operating a system with low customer density and vast geography.
- *Financial:* Ensure our actions contribute towards maximizing the value of our company, while maintaining effective access to funds on a long-term basis at reasonable rates and delivering appropriate financial returns to our shareholder.
- *Employees*: Manage the challenges of labour demographics by attracting, developing and retaining productive employees.

Performance Measures and Targets

We measure and target our performance in all of the above strategic areas, ensuring that we are recognizing the needs of all of our key stakeholders. We met or exceeded our challenging 2007 objectives, improving in a number of areas over 2006, and are moving towards achieving our strategic goals.

The potentially hazardous nature of our business requires a strong focus on safety. Consequently, one of our goals is to eliminate serious injuries. Accordingly, we measure our Serious Incident Rate to identify possible situations that may increase the risk of injury. These incidents include electrical contacts, preventable motor vehicle accidents and work equipment operations, among others. As shown in the accompanying chart, we had 4.4 serious incidents per million hours worked in 2007, which is 15% lower than 2006, 34% lower than 2005, and 39% lower than 2004. Going forward, we will continue to stress the importance of safety through a sustained cultural change and a continued focus on people and the work environment. This involves an emphasis on strong leadership, understanding and leveraging human factors and the role of human traits in determining safe work performance. Planned initiatives include increased facility and site assessments and further use of decision analysis tools to reduce human error and its consequences.



Customer satisfaction is also vital to our success. In 2007, we exceeded our overall target for customer satisfaction levels. As shown in the accompanying chart, our Large Transmission Customer Satisfaction Survey results improved from 86% to 95% satisfied, as compared to 2006. Moreover, we have seen continuous improvement over the last five years. We also continue to be conscious of the needs of our residential and small business customers and survey results show an overall satisfaction level of 82%, which remains consistent with 2006 results. We achieved our overall target for generator customer satisfaction. Within this category, we met our satisfaction target for transmission connected generators, but did not achieve our target for

distribution connected generators. Addressing the concerns identified will be an area of focus in 2008. We will continue to focus on improving the level of customer satisfaction across all customer segments by targeting our responses to the unique requirements of each segment.

We aim to retain and build public confidence and trust in our operations, as stewards of the province's electricity grid. In 2007, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for our customers in a safe, reliable and efficient fashion. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2007, we met our annual reliability targets and achieved improvements over 2006. Our continued commitment to the people of Ontario has been recognized by Corporate Knights, an independent media company focused on promoting and reinforcing sustainable development in Canada, as one of Canada's Top 50 Corporate Citizens, ranking third among utilities. The ranking was based on environment, social and governance indicators, and our conservation and demand management and smart meter programs were cited as key factors in the recognition. In addition, Corporate Knights recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada.

Given the retirement profile of our employees, we are entering into a period of significant demographic change. This change is taking place across the electricity sector and we have taken a leadership role to address the transition. As part of a comprehensive strategy to meet our staffing needs well into the future, we entered into a partnership with four community colleges of applied art and technology to attract and educate the future employees of the electricity transmission and distribution sectors. Through this partnership, we will contribute towards scholarships, program development and equipment for programs that will train people for technical, technological and trades positions in the electricity sector.

Our financial performance and the business environment in which we operate are taken into consideration in both our short-term and long-term credit ratings. In March 2007, Standard & Poor's Rating Services Inc. (S&P) assigned a positive outlook to our long-term "A" credit rating from stable, attributing the improvement to lower business risk for the sector as a whole. In November, S&P issued a commentary report which reaffirmed our assigned positive outlook while noting a steady improvement in our business risk profile. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our distribution business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period. Customers who are not eligible for the RPP, or wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004*. The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB, and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among others. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP), which was submitted for OEB review and approval on August 29, 2007. The plan's estimated 20-year capital program will be directed toward initiatives required to deliver electricity to Ontario consumers. OEB approval is expected in the Fall of 2008.

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination furthers initiatives undertaken by individual local distribution companies (LDCs), including our distribution businesses, as a result of distribution tariff rate increases approved in 2005. Our CDM programs funded through the OPA in 2007 amounted to approximately $6 million and our programs funded through distribution rates since 2005 amounted to approximately $41 million. The overall goal of the CDM programs, under the IPSP, is to reduce provincial demand by 6,300 MW by 2025.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of 800,000 smart meters in Ontario homes and businesses by the end of 2007, with installation in all homes and businesses to be completed by the end of 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely, and when combined with communications systems will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the smart meter entity that will oversee the collection and management of data. LDCs, including our distribution businesses, are accountable for the development of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time of use rates that are presently voluntary. In 2007, we deployed over 260,000 smart meters, exceeding our 2007 target of approximately 240,000 meters, and bringing the cumulative number of installations under our Smart Meter Program to approximately 288,000. We are continuing the deployment of smart meters (see Future Capital Expenditures).

Transmission Rates

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

In October 2005, the OEB initiated a proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced its decision to apply an earnings sharing mechanism (ESM) to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates were set. Consequently, 50% of our excess earnings recovered from customers were deferred as a regulatory liability.

In September 2006, we filed a transmission rate application through our subsidiary, Hydro One Networks Inc. (Hydro One Networks). On March 30, 2007, prior to their decision on our transmission rate application, the OEB issued a decision ordering that the ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, showed confidence in our work programs by approving all of our operating and capital expenditures for 2007 and 2008. However, the decision resulted in an estimated 8% annual reduction in transmission rates primarily due to a reduction in the approved return on equity from 9.88% to 8.35%, based on a formula used by the OEB in the regulation of LDCs. Further, the OEB approved final amounts and disposition treatments for certain regulatory accounts including the: RDDA, ESM and export and wheeling fees liabilities, as well as the transmission market ready regulatory asset. The RDDA and ESM will be refunded to customers over the fourteen-month period from November 1, 2007 to December 31, 2008, while the export and wheeling fees liability and transmission market ready regulatory asset will be factored into rates over the four-year period ending December 31, 2010.

As part of a joint proceeding involving all transmitters in Ontario, on October 17, 2007 the OEB approved new UTRs for implementation on November 1, 2007 through to December 31, 2008. The new rates fully reflect the approved changes to our revenue requirement and charge determinants and are, on average, 12% lower than previously approved rates. The new rates should result in approximately a 1% decrease in the average customer's total electricity bill. We anticipate the OEB will reset UTRs on January 1, 2009, at which time we anticipate our revenue requirement allocation from UTRs will increase to reflect the full repayment to customers of the ESM and RDDA. To achieve the necessary funding in support of the infrastructure required, we plan to submit a transmission rate application for 2009 to 2010 transmission rates in the Summer of 2008.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges.

Distribution Tariffs

In August 2005, we filed a distribution rate application seeking approval for an increase in the 2006 revenue requirements for our distribution businesses operated through Hydro One Networks and Hydro One Brampton Networks Inc. (Hydro One Brampton). On April 12, 2006, the OEB announced its decisions regarding these applications and, on the basis of the written and oral evidence submitted, it approved the requested increases in the revenue requirements based on an approved rate of return of 9.00%, effective May 1, 2006.

In 2006, the OEB commenced the process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Our subsidiaries, Hydro One Networks and Hydro One Brampton, applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved our submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

As our subsidiary Hydro One Networks was among 25 LDCs selected for rebasing in 2008, we submitted the revenue requirement portion of our 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64% for 2008. The requested distribution rate increase amounts to a net average increase of less than 1% on the average customer's total bill. On December 18, 2007, we filed the details of our cost allocation and rate design proposals, which include a plan to reduce the number of customer rate classes and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the latter part of 2008.

On August 2, 2007, the OEB initiated a consultation on the development of the principles and methodology for the third generation IRM. This consultative process will culminate with the issuance of an OEB report expected in mid-2008 that will be used to adjust rates starting in 2009, for those LDCs, including our subsidiary Hydro One Networks, whose 2008 rates will be rebased. On November 1, 2007, Hydro One Brampton filed its application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies. The distribution rates of our subsidiary, Hydro One Brampton, will be rebased in 2010.

Smart Meter Program

In March 2006, the OEB approved a monthly rate of 27 cents and 28 cents per metered customer, effective May 1, 2006, as initial funding for the required investment in smart meters for our subsidiaries Hydro One Networks and Hydro One Brampton, respectively. As a result, expenditures in excess of recoveries were recorded as a regulatory asset, with disposition to be established at a later date. In April 2007, as part of the OEB decision regarding the 2007 distribution rate applications made by Hydro One Networks and Hydro One Brampton, the OEB approved an amount of 93 cents and 67 cents, respectively, per month per metered customer for smart meters, for implementation effective May 1, 2007.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the approved minimum functionality for advanced metering infrastructure incurred by our subsidiaries Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets, and instead, are now classified as capital or are charged to results of operations. Expenditures determined to be above the minimum functionality for our subsidiary Hydro One Networks have been brought forward for review in our 2008 cost of service rate application. Hydro One Brampton will bring these expenditures forward in its 2010 cost of service application.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (Canadian dollars in millions)	2007	2006	$ Change	% Change
Transmission	1,242	1,245	(3)	-
Distribution	3,382	3,273	109	3
Other	31	27	4	15
	4,655	4,545	110	2
Average annual Ontario 60-minute peak demand *(MW)*[1]	22,988	22,650	338	1
Distribution – units distributed to customers *(TWh)*[1]	30.2	29.0	1.2	4

[1] System related statistics include preliminary figures for December.

Transmission

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Revenues for the year were affected by the OEB's August 16, 2007 decision on our transmission rate application. While the OEB approved all of our work program expenditure requirements, our return on equity was reduced from 9.88% to 8.35% and our deemed capital structure was adjusted from one that included common and preferred shares and debt to a deemed capital structure of 60% debt and 40% common shares. This capital structure is consistent with that approved by the OEB in 2006 which established the capital structure for Ontario's LDCs. The OEB's decision was effective January 1, 2007 and new customer rates reflecting the decision were implemented on November 1, 2007. As a result of the OEB decision, we reduced our 2007 transmission revenues to reflect the approved revenue requirement. Excess amounts collected from customers have been recorded in the RDDA and are being returned to customers through lower rates commencing November 1, 2007. On March 30, 2007, the OEB approved cessation of the ESM effective December 31, 2006 and replaced it with the RDDA. The RDDA and ESM liabilities will be drawn down over the period the new rates are in place and will be reflected in revenue over the fourteen month period from November 1, 2007 to December 31, 2008.

Our transmission revenues were lower by $3 million, compared to 2006. The OEB's August 16, 2007 transmission rate decision reduced our revenues by about $53 million. This includes the revenue adjustment associated with recording the RDDA liability and the impact of the new OEB-approved rates effective November 1, 2007. Partially offsetting this decrease was the effect of the OEB's earlier decision to end the ESM effective December 31, 2006, which increased our transmission revenues by about $33 million.

Revenues for the year also reflect higher average peak demands compared to last year, resulting in increased transmission revenues of $23 million and lower other revenues of $6 million.

Distribution

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues increased by $109 million, or 3%, in 2007 compared to last year. This change includes the recovery of increased purchased power costs of $19 million as described below under "Purchased Power." In addition, the OEB approved increases in distribution tariff rates for our subsidiaries, Hydro One Networks and Hydro One Brampton, effective May 1, 2006 and May 1, 2007 respectively. These tariff rate increases, which support the maintenance and investment requirements of our distribution system, enabling the safe and reliable delivery of electricity to our customers through Ontario, resulted in higher distribution revenues of $45 million during the year. In 2006, rates were approved based on a full cost of service hearing. In 2007, rates were approved based on OEB guidelines that included an incentive mechanism to adjust rates. Higher energy consumption, resulting primarily from the colder winter weather this year, increased our distribution revenues by a further $26 million. In addition, as a result of the OEB's decision on August 8, 2007 regarding the combined smart meter proceeding, we recorded smart meter revenues of $17 million reflecting recovery of our investments in this program. We also experienced higher other revenues of $2 million during the year.

Purchased Power

Purchased power costs incurred by our distribution business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with seasonal threshold amounts. Customers that are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP affecting the two-year period 2006 and 2007 is provided below.

Summary of RPP

	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2005	1,000	750	5.0	5.8
May 1, 2006	600	750	5.8	6.7
November 1, 2006	1,000	750	5.5	6.4
May 1, 2007	600	750	5.3	6.2
November 1, 2007	1,000	750	5.0	5.9

Purchased power costs increased in 2007 by $19 million, or 1%, to $2,240 million compared to last year. Our increased purchased power costs were primarily due to higher demand for electricity of $57 million, higher wholesale commodity prices of $25 million for customers who are not eligible for the RPP and higher wholesale market service charges levied by the IESO of $7 million. These increases were partially offset by lower costs of $62 million associated with the OEB's RPP for residential and other eligible customers, combined with the impacts of the OEB's August 16, 2007 transmission rate decision of $8 million.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (Canadian dollars in millions)	2007	2006	$ Change	% Change
Transmission	415	390	25	6
Distribution	549	460	89	19
Other	31	30	1	3
	995	880	115	13

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way increased by $25 million, or 6%, in 2007 compared to last year. Within our work programs, we continued our investments necessary for the safe and reliable operation of the transmission system. We experienced higher work program expenditures of $24 million primarily related to our planned station maintenance programs for power equipment and transformers and our line clearing and brush control programs, partially offset by lower requirements for unplanned corrective maintenance. We also experienced marginally higher expenditures in support of the transmission system. This increase reflects the commencement of a major business systems and processes project which will enable the adoption of more efficient, standardized business processes, the impact on our transmission regulatory accounts as a result of the OEB's August 16, 2007 transmission rate decision and the impact of a negotiated property tax settlement in 2006. The effect of these increases was partially offset by the impacts of a statutory reduction in our capital taxes and the reassignment of resources to support this year's larger transmission capital program.

Distribution

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system increased by $89 million, or 19%, compared to last year. Increased requirements within our work program of $65 million primarily resulted from the planned expansion of our forestry and line maintenance programs incurred to increase reliability. In addition, we experienced increased customer participation in our conservation and demand management programs. These increases were partially offset by reductions in expenditures incurred to respond to storm damage. In addition, our costs increased due to impacts of last year's OEB rate decision, including the recognition of distribution-related pension costs which had been previously deferred as a regulatory asset. Our operating, maintenance and administration expenditures also increased as a result of the OEB's August 8, 2007 decision on its combined smart meter proceeding due to the recognition of smart meter-related operating expenditures that were incurred in the 2005 to 2007 period but which were previously deferred as regulatory assets. In addition to these increases, our other support expenditures were higher by $24 million as a result of resource requirements in support of the maintenance program and the commencement of a major business systems and processes project, partially offset by the impact of a statutory reduction in our capital taxes.

Depreciation and Amortization

Depreciation and amortization expense increased by $6 million, or 1%, to $521 million this year. This increase was mainly attributable to the placement of new assets in service, consistent with our ongoing capital work program. We also experienced higher amortization of our regulatory assets resulting from an April 12, 2006 OEB distribution rate decision that was effective on May 1, 2006. These increases were partially offset by lower fixed asset removal costs resulting from lower storm damage in the year, compared to 2006.

Financing Charges

Financing charges remain unchanged at $295 million compared to last year. We experienced a lower average effective interest rate on our outstanding debt which was offset by lower capitalized interest on our regulatory assets due to lower prescribed OEB rates and increased regulatory liabilities.

Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes increased by $26 million, or 15%, to $205 million in 2007 compared to 2006. The increase is primarily due to last year's recognition of a $30 million tax benefit related to the recovery of payments in lieu of corporate taxes from prior years, taxes payable on transmission amounts received this year but not recognized as revenue for accounting purposes, and temporary differences associated with certain regulatory accounts. These increases were partially offset this year by lower taxable income and other minor temporary differences.

Net Income

Net income of $399 million was lower by $56 million, or 12%, compared to 2006 results. Net income for the year was impacted by the OEB's August 16, 2007 transmission rate decision. While the OEB approved all of our work program requirements for 2007 and 2008, our return on equity was reduced from 9.88% to 8.35% effective January 1, 2007. Our net income also reflects higher requirements to operate and safely maintain our transmission and distribution systems, including enhanced transmission station maintenance and forestry programs. Our net income was further impacted by OEB decisions, including a 2006 decision affecting our distribution-related pension expenditures, last year's property tax settlement and a higher effective tax rate. These impacts were partially offset by an increase in our distribution revenues resulting from OEB-approved increases to our distribution tariff rates, as well as increased tariff revenue in our transmission and distribution businesses due to increased peak demands and energy consumption, as well as the elimination of last year's ESM.

Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2006 through December 31, 2007. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(Canadian dollars in millions)	2007				2006			
Quarter ended	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**
Total revenues[1,2]	1,129	1,128	1,120	1,278	1,142	1,165	1,078	1,160
Net income[1,2]	90	67	93	149	101	103	99	152
Net income to common shareholder[1,2]	85	63	88	145	96	99	94	148

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's August 16, 2007 decision on Hydro One Networks' Transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (Canadian dollars in millions)	2007	2006
Operating activities	1,141	909
Financing activities		
Long-term debt issued	700	775
Long-term debt retired	(355)	(589)
Short-term notes payable	(60)	60
Dividends paid	(325)	(350)
Investing activities		
Capital expenditures	(1,091)	(823)
Other financing and investing activities	7	(2)
Net change in cash and cash equivalents	17	(20)

Operating Activities

Net cash from operating activities increased by $232 million, to $1,141 million, compared to 2006 results. Our working capital requirements were substantially lower than the comparative period primarily as a result of the impact of the *Ontario Price Credit* that was provided to RPP customers in early 2006, pursuant to regulation. Funding for the credit was received from the IESO in early December 2005. Our working capital requirements were also impacted by lower electricity prices charged to RPP customers in 2007, the impacts of last year's OEB distribution rate decision and increased accounts payable primarily associated with our capital expenditure program.

Financing Activities

Short-term liquidity is provided through funds from operations and our commercial paper program, under which we are authorized to issue up to $1 billion in short-term notes with a term to maturity of less than 365 days. At December 31, 2007, we had no short-term notes payable outstanding. The commercial paper program is supported by a committed revolving credit facility with a syndicate of banks. On January 28, 2008, we increased the facility from $750 million to $1,000 million. The maturity date remains unchanged at August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2007, we had $5,615 million in long-term debt outstanding, including the current portion. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. On June 21, 2007, we filed a $2.5 billion base shelf prospectus to renew our Medium-Term Note Program for another 25 months. Our notes and debentures mature between 2008 and 2046. We currently plan to refinance maturing debt principally through our Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million, of which $2,200 million is remaining and is currently available until July 2009.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	Aa3
Standard & Poor's Rating Services Inc.	A-1	A

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $750

million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2007, we issued $700 million in long-term debt under our Medium-Term Note Program and we repaid $355 million in maturing long-term debt. In comparison, during 2006 we issued $775 million in debt under our medium-term note program and we repaid $589 million in maturing long-term debt. In 2007, we decreased our short-term notes by $60 million compared to an increase of $60 million in 2006.

In 2007, we paid dividends to the Province in the amount of $325 million, consisting of $307 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $332 million and preferred dividends of $18 million. In 2007, cash dividends per common share were $3.070 compared to $3.320 per common share in 2006. Cash dividends per preferred share were $1.375 in each of 2007 and 2006.

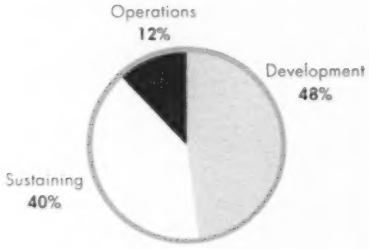
Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice, shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (Canadian dollars in millions)	2007	2006	$ Change	% Change
Transmission	560	402	158	39
Distribution	511	417	94	23
Other	20	4	16	400
	1,091	823	268	33

Transmission

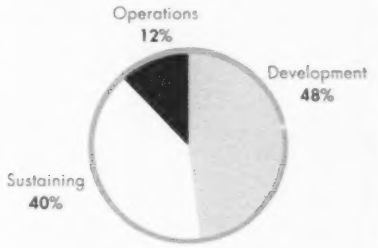


2007 Transmission Capital Expenditures

Transmission capital expenditures increased by $158 million in 2007 to $560 million, compared to 2006. Expenditures to expand and reinforce the transmission system were $271 million, representing an increase of $92 million over last year. This increase primarily reflects expenditures on our major lines and stations development projects. These projects include our new interconnection with Québec, which will increase access to emission-free hydroelectric power, our Essa to Stayner connection, which will improve the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers, and the completion of our Downtown Toronto Cable Project. Expenditures on our load and generation connections work have also increased primarily as a result of reconfiguration work at our Lambton Transformer Station and work at our London Talbot, Pleasant, and Holland transformer stations. The impact of these project expenditures was partially offset by last year's expenditure on our Niagara Reinforcement Project. This connection was substantially completed last year but final completion continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions continue between the involved aboriginal peoples and the various government entities involved. We will complete this project when site access becomes available.

Expenditures to sustain our existing transmission system were $221 million, representing an increase of $31 million compared to 2006. This increase was primarily related to the refurbishment and replacement of end-of-life lines and stations, including work at our Claireville Transformer Station to improve current reliability and to meet growing demands, and protection and control work at our switchyard facility adjoining the Pickering Nuclear Generating Station. Our other transmission capital expenditures were $68 million in 2007, representing an increase of $35 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

Distribution



2007 Distribution Capital Expenditures

Distribution capital expenditures increased by $94 million to $511 million in 2007, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $245 million, an increase of $78 million compared to last year. This increase primarily reflects our ongoing investment in smart meters. During the year we installed approximately 260,000 meters, exceeding our 2007 target of approximately 240,000 meters, and bringing our cumulative program total to about 288,000 meters. We also experienced increased expenditures for new customer connections and for planned lines work, partially offset by slightly lower expenditures related to station meters.

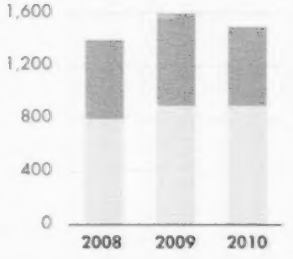
Expenditures to sustain our low-voltage distribution system were $204 million, a reduction of $21 million from 2006. This reduction was primarily a result of lower storm-related expenditures. In 2007, we experienced lower capital expenditures of about $39 million to replace assets and components damaged or destroyed by major storms. Last year an unusual number of violent storms swept through the province and, in particular, a series of severe storms was experienced last summer. This impact was partially offset by higher planned end-of-life replacements of lines assets. Our other distribution capital expenditures were $62 million in 2007, representing an increase of $37 million from last year. This increase included higher information technology expenditures primarily related to a major business systems and processes project.

Other

Other capital expenditures made to enhance our telecom infrastructure increased by $16 million to $20 million in 2007. This increase was largely due to construction of a dedicated optical network which will provide secure, high capacity connectivity across numerous healthcare locations in Ontario.

Future Capital Expenditures

Our capital expenditures in 2008 are budgeted at approximately $1.4 billion. The 2008 capital budgets for our transmission and distribution businesses are about $800 million and $600 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to exceed $1.5 billion in both 2009 and 2010, primarily reflecting increasing investments to expand, refurbish or replace transmission infrastructure. The overall investment levels reflect transmission infrastructure requirements consistent with government policy, OPA planning information, local area supply requirements and the needs of preventive and corrective maintenance to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest. These investment levels also reflect the continued mass deployment of smart meters within our distribution businesses that began in 2007. The replacement of critical information technology systems is also underway. Capital expenditures of our other business segment are budgeted at about $11 million in 2008, about half of the 2007 level, as the implementation of a dedicated fibre optic network, initiated in 2007, will be completed in 2008.



Future Capital Expenditures
(Cdn $ millions)

Transmission

Transmission system capital expenditures are anticipated to be significant over the period 2008 to 2010, amounting to about $2.5 billion. Our investment plan will address the needs of new generation development and load growth in local areas in the province. The transmission program also continues the focus on sustaining the performance of aging assets through maintenance and refurbishment programs and the replacement of assets that have reached their end of life.

With the primary focus of the recently filed IPSP being on mid to long-term timeframes, the need justification for most major urgent, short-term transmission investments will continue through Leave-to-Construct (Section 92) proceedings. Referenced in the IPSP as short to mid-term investments is the project to connect redeveloped nuclear generation and wind from the Bruce Peninsula to our Milton Switching Station, other projects of local area supply, and the installation of equipment at our existing transmission stations. OEB and environmental approvals are being sought to build the 500kV line from the Bruce Peninsula, funding for which is included in the investment plan through to 2011. Given the timeframes required for stakeholdering, approvals, and construction, interim measures are being implemented to minimize the impact of generation scheduled to be available in 2009. These are comprised of the enhancement of the protection systems, the installation of Static Var Compensators and shunt capacitor banks in Southwestern Ontario, and the upgrade of certain 230kV circuits.

Other projects included in the transmission investment plan include system expansions in Northeastern Ontario to accommodate generation on the Mattagami River; transmission reinforcements in the Greater Toronto Area (GTA), Southern Georgian Bay, Woodstock and Windsor; and the interconnection between Ontario and Québec. Construction of the Toronto third supply is contingent on the OEB approval of the IPSP and the OPA's determination of the need date. This project, for which funding is included in the plan, extends beyond the current planning horizon. This project is required to mitigate the risks associated with having only two major supply corridors to the City of Toronto and as such, to maintain a reliable supply of electricity.

At the local level, we continue to proactively address supply needs with our customers in order to meet load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes, continue to be essential. Examples of projects under construction to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston, York Region and Red Lake. To address local future needs, we are in discussions with customers for major transmission expansions or new transformer stations and, where necessary, line connections in locations such as Woodstock, Mississauga, Oshawa and Brampton. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems are expected to lead to improved reliability.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure to ensure a continued reliable supply of energy to customers throughout the province. Through targeted replacement programs for components, such as gas insulated switchgear, air blast circuit breakers, and 750 MVA autotransformers, improved performance is anticipated, which should reduce system integrity risks.

The timing of many development projects is uncertain as they are dependent upon the final approval of the IPSP and, in some instances, require approvals from various regulatory bodies, as well as negotiations and consultations with customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

Distribution

Capital expenditures for the period 2008 to 2010 are estimated to be approximately $2 billion, including the Smart Meter Program, and core development and sustainment programs. With approximately 1.3 million customers in our service territory, we anticipate installing about a further 1 million meters under the program. Consistent with the government policy, all homes and small businesses are to receive a smart meter by 2010. At the Province's request, we will review our implementation plan and associated costs for the period from 2008 to 2010. Smart Network is an initiative that would leverage the smart meter infrastructure to enable functionality across our rural territory. This is currently being piloted and validated, and will be brought forward for consideration if benefits are confirmed.

Our core work will focus on demand programs such as new load connections, trouble calls and storm damage, and system capability reinforcement. The distribution investment plan also includes program expenditures relating to preserving the performance of our aging distribution asset base in order to improve system reliability. These include increased wood pole replacements, feeder sectionalization, and defect management, together with improved maintenance and line clearing practices. Given initiatives to encourage renewable energy technologies, we are experiencing increased distribution generation connection activity. Connection impact assessments are undertaken to determine project feasibility. Under OEB rules, the generator will pay connection costs other than distribution upgrades that also benefit other customers. No provision has been included in the plan for major distribution system modifications to accommodate this growth of new generation.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2007 (Canadian dollars in millions)	**Total**	**2008**	**2009/2010**	**2011/2012**	**After 2012**
Contractual Obligations *(due by year):*					
Long-term debt – principal repayments	5,615	540	800	850	3,425
Long-term debt – interest payments	5,211	307	554	488	3,862
Inergi LP (Inergi) outsourcing agreement[1]	396	100	190	106	-
Operating lease commitments	16	6	7	2	1
Total Contractual Obligations[5]	11,238	953	1,551	1,446	7,288
Other Commercial Commitments *(by year of expiry):*					
Bank line[2]	750	-	750	-	-
Letters of credit[3]	99	99	-	-	-
Guarantees[3]	325	325	-	-	-
Pension[4]	196	94	102	-	-
Total Other Commercial Commitments	1,370	518	852	-	-

[1] On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services.

[2] As a backstop to our commercial paper program, we have a $750 million revolving standby credit facility with a syndicate of banks which matures in August 2010. On January 28, 2008 this facility was increased to $1,000 million.

[3] We currently have bank letters of credit of $95 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million. The maximum parental guarantee was increased in November 2007 to $325 million as a result of forecast power purchases and the November 1, 2007 change to our transmission rates. Although no letters of credit are currently required for prudential support, we would have to resume providing bank letters of credit if our highest long-term credit rating deteriorated to below the "Aa" category. The remaining amounts included in letters of credit pertain to operating letters of credit and to surety bonds.

[4] Contributions to the pension fund are made one-month in arrears. Contributions for 2008 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2008 and 2009 will be about $94 million. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

[5] In addition, the Company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these are considered individually material, and the majority will result in payments by our Company by December 31, 2008.

The amounts in the above table under long-term debt – principal repayments, are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to, the IESO, which is a related party by virtue of its status as an agency of our shareholder. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends which are paid to the Province and our payments in lieu of corporate income taxes which are paid or payable to the OEFC.

RISK MANAGEMENT AND RISK FACTORS

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices, and our Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence our major business and corporate decisions. We have entered into a shareholder agreement with the Province relating to certain aspects of the governance of our company.

Conflicts of interest may arise as a result of the Province's obligation to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province's ownership of Ontario Power Generation Inc. (OPG), and the determination of the amount of dividend or payments in lieu of corporate income taxes. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us.

Risk Associated with Transmission Projects

Significant investments have been initiated to increase transmission capacity and enable the reliable delivery of power to Ontario consumers from existing and future generation sources. In many cases, initiating these investments is contingent upon one or more approvals. These can include Section 92, expropriation and environmental approvals, as well as consultation, and possibly accommodation with First Nations where traditional lands or lands subject to land claims are involved. The ability to make such investments may also be impacted by public opposition. If we are unable to make such investments, the reliability of our transmission system and our service quality could be adversely affected.

Work Force Demographic Risk

More than 20% of our employees will be eligible for retirement by the end of 2008. We expect the skilled labour market for our industry to be highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rate of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either or both of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2010. These expectations are factored into our revenue requirements for OEB approval. There is a risk that our revenues would be reduced if these targets are exceeded. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors. For example, revisions to the OEB's *Transmission System Code* have resulted in customers gaining the right to bypass some of our transformation facilities by constructing their own assets under certain conditions.

As a transmitter, we expect to make significant investment in the coming years in large-scale transmission infrastructure projects, and to connect new third-party load and generation assets. Additionally, there is always the possibility that we could incur unexpected capital expenditures to maintain or improve our assets. The risk exists that the OEB may not allow full recovery of such investments. To the extent possible, we try to mitigate this risk by seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

The Province has passed regulations authorizing our subsidiaries, as distributors, to procure smart meters. Of the associated costs in rates, our subsidiaries Hydro One Networks and Hydro One Brampton are only currently authorized to recover 93 cents and 67 cents per metered customer per month, respectively. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential impairment and charges to results of operations.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain the performance that is needed to support transmission reliability and service quality to our customers. Capital and maintenance programs have been increasing to maintain the performance of our aging asset base. However, execution of these plans is dependent on external factors including limited opportunities to remove equipment from service to accommodate construction due to outage constraints as determined by the IESO and substantially increased lead times for material and equipment due to increased global demand and limited vendor capability. Consequently, the necessary maintenance or replacements may be delayed, which could affect transmission reliability.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for the recovery. However, there is no assurance that the OEB would approve such an application.

Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $900,000 per year that we currently are paying to these Indian bands and bodies. If we cannot obtain consents from the Indian bands and bodies, the OEFC will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations or replace them at a cost that could be substantial. These potential costs could have a material adverse effect on our results of operations if we are unable to recover them in future rate orders.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Energy Professionals. The existing collective agreements with the PWU will expire on March 31, 2008; collective bargaining commenced in January 2008. The Society of Energy Professionals collective agreement was recently renewed and now expires on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face operational risk related to continued compliance with our license requirements of providing service to customers.

Environmental Risk

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centers. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

Future changes in environmental regulations may result in material changes to our estimates of future expenditures to complete this work. On November 4, 2006, Environment Canada published new draft regulations governing the management of polychlorinated biphenyls (PCBs). These draft regulations may be finalized in 2008. We have estimated the non-capital expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts we have already recorded as environmental liabilities on our Balance Sheet. If required, most of these additional expenditures would be incurred in the period from 2013 to 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In any case, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our Balance Sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems that are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems to capture data and to produce timely and accurate information. We are working to transition most of our financial and business processes to an integrated business and financial reporting system which will enable productivity through the adoption of more efficient,

standardized business processes. The conversion of these systems and processes may expose us to risk, including risks associated with maintaining internal controls, as new systems are brought online and the data and business processes are transitioned. System failures could have a material adverse effect on our company.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have a material adverse effect on our results of operations.

Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use provincially-owned transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The most recently filed valuation was prepared as at December 31, 2006 and was filed in September 2007. Our annual pension contributions for the three year period 2007 to 2009 are approximately $94 million per year. The next valuation is required to be prepared as at December 31, 2009. The required level of contributions effective January 1, 2010 will depend on future investment returns, changes in benefits and changes in actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time. The recovery of pension costs is subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and to fund capital expenditures. A substantial portion of our existing debt matures between 2008 and 2011. We are also planning a combined total of capital expenditures of approximately $3 billion in 2008 and 2009. Cash generated from operations will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our business.

Market and Credit Risk

Market risk refers primarily to risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk and our foreign exchange risk is currently insignificant, although we could in future decide to issue foreign currency denominated debt. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formula approach which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in determining our rate of return would reduce our transmission business' results of operations by approximately $20 million and our distribution business' results of operations by approximately $13 million. Our results of operations are adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest rate swap agreements to mitigate elements of interest rate risk. We estimate that a 1% increase in interest rates on the refinancing of long-term debt maturing in 2008 and 2009 would reduce our results of operations by approximately $1 million and $4 million, respectively.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, and by entering into master agreements which enable net settlement. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code*.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements:

Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2007 amounted to $213 million and principally relate to regulatory asset recovery accounts (RARAs), employee future benefits other than pension, and environmental costs. We have also recorded regulatory liabilities amounting to $583 million as at December 31, 2007. These amounts pertain primarily to pension, the RDDA, export and wheeling fees, the ESM, and retail settlement variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. Most of our regulatory accounts have already been reviewed by the OEB and confirmed as recoverable or refundable.

If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to settle obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of PCB-contaminated assets and mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. These future expenditures are discounted using factors ranging from 2.9% to 6.25%. Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, and the number and contamination levels of assets with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions are approximately $94 million per year over the period 2007 through to 2009. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 6.75% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% in alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. The return on pension plan assets was lower than this long-term assumption in 2007.

The weighted-average discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2007 increased by 0.25% from those at December 31, 2006 in conjunction with increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $12 million per year and an increase in the year end obligation of about $167 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

Goodwill

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2007 and we determined that the carrying value of our goodwill has not been impaired.

EMERGING ACCOUNTING PRONOUNCEMENTS

Transition to International Financial Reporting Standards (IFRS)

The Canadian Accounting Standards Board (AcSB) ratified a new strategic plan for the period of 2006-2011 that entails converging Canadian generally accepted accounting principles (GAAP) with IFRS over the five-year transitional period. The final AcSB decision to proceed on the intended schedule will be made in March 2008. It is generally expected that the decision to adopt IFRS will be confirmed unless some unexpected event occurs. The AcSB has adopted an implementation plan and suggests that companies be in a position to disclose their implementation plans for the IFRS changeover in their 2008 Management, Discussion and Analysis (MD&A). The Canadian Securities Administrators will be defining the MD&A disclosure requirements regarding an enterprise's plans for IFRS conversion. We started planning our transition to IFRS during 2006 and plan to commence convergence work beginning in 2008.

Accounting for Rate Regulated Operations

During 2007, the AcSB issued an exposure draft proposing to remove all specific references to rate regulated accounting from the Handbook of the Canadian Institute of Chartered Accountants (CICA). In August 2007, the AcSB decided to remove a temporary exemption in CICA Handbook Section 1100, retain existing references to rate regulated accounting in the CICA Handbook, require the recognition of future income tax liabilities and assets as well as a separate regulatory asset or liability for the amount of future income taxes, and retain existing requirements to disclose the effects of rate regulation.

The new rules will apply prospectively to interim and annual financial statements relating to fiscal years beginning on or after January 1, 2009 and will result in accrual accounting being followed for payments in lieu of corporate taxes. Such amounts are currently accounted for on a cash basis, consistent with specific OEB rate-setting direction. Commencing the first quarter of 2009, the regulatory impact of the OEB's direction will be reflected through the recognition of regulatory assets and/or liabilities. There will be no impact on results of operations.

Inventories

The AcSB issued new CICA Handbook Section 3031, *Inventories*, which is effective for our company in the first quarter of 2008. The recommendations apply to our materials and supplies inventories and require major spare parts to be classified as future use fixed assets rather than inventory. We anticipate a significant transfer of book value from the materials and supplies category on the Balance Sheet to fixed assets. Additionally, the new handbook section will allow the reversal of prior period write-downs when the net realizable value of impaired inventory subsequently recovers.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

As a reporting issuer we are required to comply with the Ontario Securities Commission's Multilateral Instrument 52-109 (Multilateral Instrument) concerning internal control and related certifications, often referred to as Bill 198. During 2005 and 2006, we documented all of our processes, risks and controls, and completed all testing necessary to make the required annual certifications. Commencing with our Consolidated Financial Statements for the year ended December 31, 2005, we certified that our disclosure controls and procedures provide reasonable assurance that all information considered necessary for appropriate disclosure has been accumulated and communicated to management on a timely basis. Commencing with our Consolidated Financial Statements for the year ended December 31, 2006, we also made certifications regarding the design of our internal controls over financial reporting.

Our focus for 2007 has been the ongoing sustainment of our control environment, including communication, evaluation and enhancements, as required to support the certifications of our President and Chief Executive Officer, and Chief Financial Officer (Certifying Officers). We have also carried out a comprehensive plan to test the operational effectiveness of our internal controls over financial reporting.

In compliance with the requirements of the Multilateral Instrument, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2007, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and that they operated effectively during the period. Further, our Certifying Officers have also certified that internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2005, 2006 and 2007. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statement of Operations

Year ended December 31 (Canadian dollars in millions, except earnings per common share)	**2007**	**2006**	**2005**
Revenues[1]	4,655	4,545	4,416
Net income[1]	399	455	483
Basic and fully diluted earnings per common share *(Canadian dollars)*	3,809	4,366	4,652

Consolidated Balance Sheet

Year ended December 31 (Canadian dollars in millions, except cash dividends per share)	**2007**	**2006**	**2005**
Total assets[2]	12,790	12,210	11,798
Total long-term debt[3]	5,603	5,243	5,032
Cash dividends per common share *(Canadian dollars)*	3,070	3,320	2,730
Cash dividends per preferred share *(Canadian dollars)*	1.375	1.375	1.375

[1] As a result of the OEB's August 16, 2007 decision on Hydro One Networks' Transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.
[2] Total assets for 2006 and 2005 reflect the reclassification of deferred debt costs in 2007, applied retroactively
[3] Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

OUTLOOK

To meet our challenge of being the best transmission and distribution company in North America, we will continue to concentrate on our strategic priorities relating to respect of the public trust, safety, our customers, system reliability, financial stewardship and our employees. Significant improvements have been made toward achieving our customer satisfaction and safety targets, while we maintain our financial profile and reliability performance. Our continued commitment to the people of Ontario has been recognized by the Edison Electric Institute (EEI) and by Corporate Knights magazine. Early in the year, EEI honoured us with the "Emergency Recovery Award" for outstanding storm restoration efforts in 2006. This was the first time a non-U.S. utility has won this prestigious award. Corporate Knights magazine recognized us as one of Canada's top 50 corporate citizens based on environmental, social and governance indicators. Our CDM program and leadership in the Smart Metering initiative were cited as key factors contributing to our ranking of third among utilities. This magazine also recognized us as Canada's most diverse utility and ranked us fifth overall in corporate Canada, based on the composition of our Board, senior executives and the company's practices and policies on diversity. In addition, Hydro One was selected as the recipient of the Utility Planning Network's 2007 Metering Award in the category of Automated Meter Reading Initiative – North American Municipal or Cooperative among numerous entries from around the globe.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability. Our transmission investment plan supports the achievement of the Province's renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs, and facilitates the integration of new supply.

In its transmission rate decision issued on August 16, 2007, the OEB approved our entire operation, maintenance and administration and capital work programs applied for in 2007 and 2008, expressing confidence in our ability and expertise to make an appropriate assessment of what is needed "to maintain a robust, safe, and reliable transmission system". However, the decision was not favourable in other areas such as the approved return on equity. We plan to file a transmission rate application for 2009 and 2010 rates. These rates, if approved, should provide the funding required to maintain and meet the infrastructure requirements of the transmission system in the public interest.

Our investment plan does not include spending for large scale investments, such as the east-west transmission grid or potential long-term transmission projects identified in the IPSP. For certain long-term projects addressing generation-enabling connection lines and reliability of local area supply, the IPSP recommends that project development work (preliminary engineering, cost estimating, options assessment, and Environmental Assessment and Section 92 approvals, as required) begin upon approval of the IPSP by the OEB. As such, we would be prepared to initiate project development work for these projects to enable expedited construction once a need date is confirmed by the OPA and once we have a reasonable expectation of cost recovery through rates. For some projects such as the transmission connection for generation in the Nipigon area, the IPSP recommends that development work commence in 2008. It is anticipated that the final decision to proceed with the longer term major projects, such as new high voltage transmission lines from north to south, will be made when the next IPSP is prepared in about three years.

The 2006 distribution rate decision has provided a base funding level to build upon. The 2008 Cost of Service application supports the implementation of our Smart Meter Program, and enhances sustainment programs to improve reliability and customer service. In 2007, an OEB decision clarified the recoverability of costs associated with the minimum level of smart meter functionality, thereby reducing the uncertainty of recovery of this program. Smart meter costs in excess of minimum functionality will be reviewed as part of the 2008 Cost of Service hearing. Given the magnitude and unique nature of the Smart Meter Program, recovery of costs will be a key focus. In addition, the distribution investment plan does not provide for the implementation of a Smart Network, which would leverage the smart meter technology to enable further internal productivity initiatives through wireless broadband.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2006, the Government announced a two-year exemption of the electricity transfer tax. We will consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis, where they are consistent with our strategy and direction from our shareholder. The investment plan does not include any funding for any LDC acquisitions or divestitures.

Key enablers of the successful implementation of the work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through partnering with universities, colleges and our unions, as well as skills development and retention. Significant retirement projections and increasing work volumes will result in an unprecedented number of new hires in the near-term. With regard to materials, we are seeing increasing lead times and costs as market shortages emerge globally. Consequently, sourcing strategies are being developed and implemented to ensure availability of materials to support the work programs.

Through the outlook period, we anticipate no changes to our role within the industry and that our financial returns will be sufficient to maintain our credit quality. In November 2007 the Agency Review Panel issued the second phase of its report on Ontario's provincially-owned electricity agencies. The report confirmed that, overall, Ontario's electricity sector and the provincial agencies within it are functioning reasonably well. We do not anticipate any structural changes to our company.

FORWARD LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this MD&A, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to statements about our strategy; statements related to the IPSP and projects flowing therefrom; statements about smart meters including costs, cost recovery and deployment and/or implementation plans; expectations regarding the timing, content and impact of future applications and decisions related to our transmission and distribution businesses; the anticipated results on our business processes and productivity as a result of our business systems and processes project; the anticipated impact of CDM programs; statements regarding the reliability of our distribution and transmission systems; expectations regarding load growth and new generation; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licenses, rates, rate orders, cost recovery, rates of return, rate structures and revenue requirements in both our transmission and distribution businesses and the timing of decisions from the OEB; statements regarding future capital expenditures and our investment plans; expectations regarding the results of our on-going and planned projects; expectations regarding our strategy for acquisitions or divestitures of distribution assets; expectations regarding future pension contributions; expectations regarding workforce demographics; expectations regarding environmental expenditures and other environmental matters including the need for environmental approvals and assessments; expectations regarding borrowing requirements; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements regarding provincial ownership of our transmission corridors; the estimated impact of changes in the forecast long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; the estimated impact of changes in interest rates on our results of operations; statements about employee future benefit costs; statements about emerging accounting pronouncements; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, and structural changes to our company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third party industry analysts. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content of the final IPSP, as approved by the OEB;
- delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including potential conflicts of interest that may arise between us, the Province and related parties;
- the risks related to our work force demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;

- regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the potential impact of CDM programs on our load and our revenues;
- the potential impact of not being able to recover all of our project costs associated with the installation of smart meters;
- unanticipated changes in electricity demand or in our costs;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the inability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the potential for substantial and currently undetermined environmental costs and liabilities;
- the risks associated with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated;
- the impact of the ownership by the Province of lands underlying our transmission system;
- the potential impact of not being able to recover our pension costs;
- the risk that we are not able to arrange sufficient cost effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks of counter-party default on our outstanding derivative contracts;
- the risks associated with changes in interest rates; and
- the risks associated with changes in the forecast long-term Government of Canada bond yield.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under "Risk Management and Risk Factors" in this MD&A. You should review the section entitled "Risk Management and Risk Factors" in detail.

This MD&A is dated as at February 13, 2008. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 13, 2008.

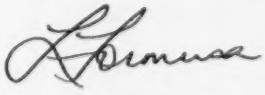
In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition internal and disclosure controls have been documented, evaluated, tested and identified consistent with Multilateral Instrument 52-109 (Bill 198). An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by Ernst & Young LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Auditors' Report, which appears on page 28, outlines the scope of their examination and their opinion.

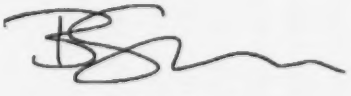
The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures, and the design of related internal controls over financial reporting pursuant to Multilateral Instrument 52-109.

On behalf of Hydro One Inc.'s management:



Laura Formusa
President and Chief Executive Officer



Beth Summers
Chief Financial Officer

HYDRO ONE INC.
AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the Consolidated Balance Sheets of Hydro One Inc. (the Company) as at December 31, 2007 and December 31, 2006, and the Consolidated Statements of Operations, Retained Earnings and Cash Flows of the Company for each of the years in the two-year period ended December 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these Consolidated Financial Statements present fairly, in all material respects, the financial position of the Company as at December 31, 2007 and December 31, 2006 and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2007 in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Ernst & Young LLP
Chartered Accountants
Licensed Public Accountants
Toronto, Canada

February 13, 2008

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Revenues		
Transmission *(Notes 7 and 13)*	1,242	1,245
Distribution *(Note 13)*	3,382	3,273
Other	31	27
	4,655	4,545
Costs		
Purchased power *(Note 13)*	2,240	2,221
Operation, maintenance and administration *(Note 13)*	995	880
Depreciation and amortization *(Note 3)*	521	515
	3,756	3,616
Income before financing charges and provision for payments in lieu of corporate income taxes	899	929
Financing charges *(Note 4)*	295	295
Income before provision for payments in lieu of corporate income taxes	604	634
Provision for payments in lieu of corporate income taxes *(Notes 5 and 13)*	205	179
Net income	399	455
Other comprehensive income	3	-
Comprehensive income	402	455
Basic and fully diluted earnings per common share *(Canadian dollars) (Note 12)*	3.809	4.366

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 (Canadian dollars in millions)	**2007**	**2006**
Retained earnings, January 1	1,184	1,079
Net income	399	455
Dividends *(Note 12)*	(325)	(350)
Retained earnings, December 31	1,258	1,184

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS

December 31 (Canadian dollars in millions)	2007	2006
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts - $21 million; 2006 - $19 million) *(Note 13)*	759	777
Regulatory assets *(Note 7)*	103	121
Materials and supplies	67	56
Other	17	13
	946	967
Fixed assets *(Note 6)*:		
Fixed assets in service	16,812	16,238
Less: accumulated depreciation	6,220	6,180
	10,592	10,058
Construction in progress	622	468
	11,214	10,526
Other long-term assets:		
Deferred pension asset *(Note 10)*	380	382
Regulatory assets *(Note 7)*	110	190
Goodwill	133	133
Other assets	7	12
	630	717
Total assets	12,790	12,210

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS (continued)

December 31 (Canadian dollars in millions)	2007	2006
Liabilities		
Current liabilities:		
Bank indebtedness	12	29
Accounts payable and accrued charges *(Notes 11 and 13)*	731	661
Regulatory liabilities *(Note 7)*	114	-
Accrued interest	55	49
Short-term notes payable *(Note 8)*	-	60
Long-term debt payable within one year *(Note 8)*	540	395
	1,452	1,194
Long-term debt *(Note 8)*	5,063	4,848
Other long-term liabilities:		
Employee future benefits other than pension *(Note 10)*	855	803
Regulatory liabilities *(Note 7)*	469	473
Environmental liabilities *(Note 11)*	52	55
Long-term accounts payable and accrued charges	13	16
	1,389	1,347
Total liabilities	7,904	7,389
Contingencies and commitments *(Notes 9, 15 and 16)*		
Shareholder's equity *(Note 12)*		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	1,258	1,184
Accumulated other comprehensive income	(9)	-
Total shareholder's equity	4,886	4,821
Total liabilities and shareholder's equity	12,790	12,210

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

R. Burak

W. Murray

Rita Burak
Chair

Walter Murray
Chair, Audit and Finance Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (Canadian dollars in millions)	2007	2006
Operating activities		
Net income	399	455
Adjustments for non-cash items:		
Depreciation and amortization (net of removal costs)	482	474
Revenue difference deferral account	73	-
Retail settlement variance accounts	46	7
Other regulatory asset and liability accounts	1	19
Transmission earnings sharing mechanism	-	33
Amortization of debt discount	5	27
	1,006	1,015
Changes in non-cash balances related to operations *(Note 14)*	135	(106)
Net cash from operating activities	1,141	909
Financing activities		
Long-term debt issued	700	775
Long-term debt retired	(355)	(589)
Short-term notes payable	(60)	60
Dividends paid	(325)	(350)
Other	(1)	(4)
Net cash used in financing activities	(41)	(108)
Investing activities		
Capital expenditures	(1,091)	(823)
Other assets	8	2
Net cash used in investing activities	(1,083)	(821)
Net change in cash and cash equivalents	17	(20)
Cash and cash equivalents, January 1	(29)	(9)
Cash and cash equivalents, December 31 *(Note 14)*	(12)	(29)

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc., Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Company Inc. and Hydro One Network Services Inc.

Hydro One Brampton Inc. was dissolved on January 30, 2007. Hydro One Network Services Inc. was dissolved on December 14, 2006. Hydro One Delivery Services Inc. will be dissolved pursuant to the *Business Corporations Act* (Ontario).

Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

Rate-setting

The rates of the Company's electricity transmission and distribution businesses are subject to regulation by the OEB. In October 2005, the OEB initiated a proceeding to review Hydro One Network's transmission rates and to approve revenue requirements for 2006, 2007 and 2008 based on cost of service regulation. On February 21, 2006, the OEB announced a decision to apply an earnings sharing mechanism (ESM) to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for the period January 1, 2006 until new transmission rates were set.

In September 2006, Hydro One Networks filed a transmission rate application. On March 30, 2007, prior to their decision on our transmission rate application, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The decision also approved the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, approved all operating and capital expenditures for 2007 and 2008. However, the decision resulted in a reduction in the approved return on equity from 9.88% to 8.35%. The OEB also approved final amounts and disposition treatments for certain regulatory liabilities including: the RDDA, the ESM and export and wheeling fees, as well as the transmission market ready regulatory asset.

The Company's distribution rates are also based on a revenue requirement that includes a rate of return. On April 12, 2006, the OEB announced its decision regarding the Company's rate applications in respect of the distribution businesses of Hydro One Networks and Hydro One Brampton. On the basis of the written evidence submitted, the OEB approved the requested increase in the revenue requirement based on a reduction in the approved rate of return, from a targeted 9.88% to 9.00%, effective May 1, 2006.

In 2006, the OEB commenced a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process includes a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Hydro One Networks and Hydro One Brampton applied for marginal distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation, efficiency targets and significant events outside the control of management. In April 2007, the OEB approved the Company's submissions on the basis of its cost of capital and second generation IRM policies, and the revised rates were implemented effective May 1, 2007.

Hydro One Networks submitted the revenue requirement portion of its 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan on August 15, 2007. This application seeks the approval of a revenue requirement of $1,067 million based on a return of 8.64% for 2008. On December 18, 2007, Hydro One Networks filed the details of its cost allocation and rate design proposals, which include a plan to reduce the number of rate classes for its customers and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes. Based on the OEB's processing guidelines, a decision is anticipated in the Fall of 2008. On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's cost of capital and second generation IRM policies.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 7.

Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2007 amounted to $413 million (2006 - $386 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Corporate Income and Capital Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act, 1998*, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

Materials and Supplies

Materials and supplies represent spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Fixed Assets

Fixed assets are capitalized at cost which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets and easements. Fixed assets also include future use assets such as land and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset retirement obligation will be recognized at that time.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

Distribution

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

Easements

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other amounts related to access rights.

Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction based on the OEB's approved allowance for funds used during construction (2007 – 5.20%; 2006 – 6.39%).

Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which are depreciated on a declining balance basis.

Effective January 1, 2007, the Company prospectively revised its fixed asset depreciation rates resulting from a periodic external review required by the OEB. The estimated impact of the change in rates is a reduction in depreciation expense of approximately $7 million per annum. A summary of the new rates for the various classes of assets is included below:

	Depreciation rates (%)	
	Range	Average
Transmission	1% - 4%	2%
Distribution	1% - 13%	2%
Communication	1% - 13%	5%
Administration and service	1% - 20%	8%

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in rates.

Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations.

The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the distribution business segment.

Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

Financial Instruments

Effective January 1, 2007, the Company adopted four new accounting standards comprising the following sections of the Handbook of the Canadian Institute of Chartered Accountants (CICA): 1530, *Comprehensive Income*; 3855, *Financial Instruments – Recognition and Measurement*; 3861, *Financial Instruments – Disclosure and Presentation*; and 3865, *Hedges*. The adoption of these new standards required changes in the accounting for financial instruments and hedges, and the recognition of certain transition adjustments that were recorded in opening accumulated other comprehensive income (AOCI) as described below, consistent with the CICA Handbook sections. The comparative annual Consolidated Financial Statements have not been restated. The principal changes in the accounting for financial instruments and hedges due to the adoption of these accounting standards are described below.

Comprehensive Income

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges, and the change in fair value on existing cash flow hedges. The impact of the amortization of net hedging losses that were discontinued prior to the transition date was immaterial to the Statement of Operations.

Financial Assets and Liabilities

Under the new standards, all financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows:

Short-term investments	Held-to-maturity
Long-term accounts receivable	Loans and receivables
Bank indebtedness	Other liabilities
Short-term notes payable	Other liabilities
Long-term debt (excluding MTN Series 8 Note)	Other liabilities
MTN Series 8 Note	Designated as held-for-trading

The MTN Series 8 Note is a step-up coupon note with extendable maturity dates up to 2011. (See Notes 8 and 9)

Where there is an economic hedge, as in the case of the MTN Series 8 note and associated interest rate swap, the Company has applied the fair value option without hedge accounting. The impact was not material.

All financial instrument transactions are recorded at trade date.

Derivatives and Hedge Accounting

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective. The impact of the change in the accounting policy related to embedded derivatives was not material.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documents the relationship between the hedging instrument and the hedged item. This would include linking all derivatives to specific assets and liabilities on the Consolidated Balance Sheet or to specific firm commitments or forecasted transactions. The Company would also assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives that are used are effective in offsetting changes in fair values or cash flows of hedged items.

Upon adoption of the new standards, the Company reclassified unamortized hedging losses on cash flow hedges that had been discontinued prior to the transition date to AOCI. The hedging losses are amortized to financing charges using the effective interest method over the term of the hedged debt.

Transaction Costs

Transaction costs for financial assets and liabilities that are other than held-for-trading, are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method. The impact of the change in amortization basis from an annuity method to the effective interest method was not material.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

Environmental Costs

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the net present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

3. DEPRECIATION AND AMORTIZATION

Year ended December 31 (Canadian dollars in millions)	2007	2006
Depreciation of fixed assets in service	384	379
Fixed asset removal costs	39	41
Amortization of regulatory and other assets	98	95
	521	515

4. FINANCING CHARGES

Year ended December 31 (Canadian dollars in millions)	2007	2006
Interest on short-term notes payable	4	2
Interest on long-term debt payable	308	296
Amortization of debt discount	5	27
Other	7	9
Less: Interest capitalized on construction in progress	(24)	(28)
Interest accreted on regulatory accounts	-	(7)
Interest earned on investments	(5)	(4)
	295	295

5. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows:

Year ended December 31 (Canadian dollars in millions)	2007	2006
Income before provision for PILs	604	634
Federal and Ontario statutory income tax rate	36.12%	36.12%
Provision for PILs at statutory rate	218	229
Increase (decrease) resulting from:		
Net temporary differences:		
Transmission amounts received but not recognized for accounting purposes	25	12
Retail settlement variance accounts	17	2
Pension contributions in excess of pension expense	(13)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(12)	(11)
Interest capitalized for accounting purposes but deducted for tax purposes	(9)	(13)
Capital cost allowance in excess of depreciation and amortization	(9)	(3)
Employee future benefits other than pension expense in excess of cash payments	7	14
Environmental expenditures	(4)	(6)
Recovery of PILs related to prior years	-	(30)
Other	(5)	2
Net temporary differences	(3)	(49)
Net permanent differences	(10)	(1)
Provision for PILs	205	179
Effective income tax rate	33.94%	28.23%

In 2006, Hydro One recognized a tax benefit of approximately $30 million in respect of a recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2007, future income tax liabilities of $253 million (2006 - $281 million), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been lower by approximately $28 million (2006 – higher by $16 million), including the impact of a change in substantively enacted tax rates.

Future income taxes relating to the non-regulated businesses have also not been recorded in the accounts as they have not met the criterion of "more likely than not" to be realized. As at December 31, 2007, future income tax assets of $4 million (2006 - $4 million), based on substantively enacted income tax rates, have not been recorded.

6. FIXED ASSETS

December 31 (Canadian dollars in millions)	Fixed Assets in Service	Accumulated Depreciation	Construction in Progress	Total
2007				
Transmission	8,708	3,152	370	5,926
Distribution	5,902	2,133	115	3,884
Communication	739	305	58	492
Administration and service	978	556	79	501
Easements	485	74	-	411
	16,812	6,220	622	11,214
2006				
Transmission	8,293	3,024	359	5,628
Distribution	5,651	2,129	86	3,608
Communication	822	383	18	457
Administration and service	989	583	5	411
Easements	483	61	-	422
	16,238	6,180	468	10,526

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $24 million in 2007 (2006 - $28 million).

7. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (Canadian dollars in millions)	2007	2006
Regulatory assets:		
Regulatory asset recovery account II	66	87
Environmental	65	70
Employee future benefits other than pension	42	84
Regulatory asset recovery account I	19	58
Market ready	13	-
Smart meters	4	10
Other	4	2
Total regulatory assets	213	311
Less: current portion	103	121
	110	190
Regulatory liabilities:		
Deferred pension	380	382
Revenue difference deferral account	73	-
Retail settlement variance accounts	50	2
Export and wheeling fees	38	49
Transmission earnings sharing mechanism	28	34
Other	14	6
Total regulatory liabilities	583	473
Less: current portion	114	-
	469	473

Regulatory assets

Regulatory asset recovery account II (RARA II)

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $23 million (2006 - $16 million). In addition, related financing charges would have been higher by $3 million (2006 - $5 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2030. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $12 million (2006 - $17 million).

Employee future benefits other than pension

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a

regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has a remaining recovery period of 1 year (2006 - 2 years) and does not earn a return. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $42 million (2006 - $42 million).

Regulatory asset recovery account I (RARA I)

On December 9, 2004, the OEB issued a decision on the prudence of the distribution related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. Hydro One Networks has requested an extension of the period for the RARA I recovery until such time as new rates are implemented. The RARA I includes distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. Any over or under recovery of the RARA I due to continuance of the rate rider will be tracked for disposition at a future date. In the absence of rate regulated accounting, amortization expense in 2007 would have been lower by $20 million (2006 - $20 million). In addition, related financing charges would have been higher by $1 million (2006 - $3 million).

Market ready

In September 2006, as part of its transmission rate application, Hydro One Networks applied for the recovery of various regulatory deferral accounts including the transmission market ready costs incurred in connection with market opening. The transmission related transition-costs were incurred to meet IESO requirement associated with registration and authorization activities. On August 16, 2007, as a result of the oral and written evidence the OEB approved the recovery of substantially all of these costs. Consequently, the market ready regulatory asset was established and recovery is being factored into rates over the four-year period ending December 31, 2010. In the absence of rate regulated accounting, operation, maintenance and administration expense would have been higher by $16 million (2006 - $nil) and revenue would have been higher by $4 million (2006 - $nil).

Smart meters

On March 21, 2006, the OEB approved the establishment of regulatory deferral accounts for smart meter-related expenditures and a monthly customer charge of 27 cents and 28 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively, was reflected in Hydro One's revenue requirement. Consistent with the OEB's direction and pending further guidance, the Company recognized a regulatory asset consisting of the net balance of capital and operating expenditures for smart meters less recoveries received from customers. In April 2007, as part of its decision regarding the Company's 2007 distribution rate applications, the OEB increased the monthly customer charge effective May 1, 2007 to 93 cents and 67 cents per metered customer for Hydro One Networks and Hydro One Brampton, respectively.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the minimum functionality for advanced metering infrastructure incurred by Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets. Such expenditures are now classified as capital or are charged to results of operations consistent with the Company's standard accounting practices. Expenditures determined to be above the minimum functionality have been brought forward for review in Hydro One Networks cost of service rate application filed in 2007.

The OEB decision also required that related revenues be based upon a calculated revenue requirement specific to smart meters. As a result, the carrying value of the smart meter regulatory asset account represents the difference between revenue recorded on this basis and actual recoveries received under existing rate adders. In the absence of rate regulated accounting, year-to-date operation, maintenance and administration expense would have been lower by $3 million (2006 – higher by $4 million) and revenues would have been lower by $2 million (2006 – higher by $2 million).

Regulatory liabilities

Deferred pension

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate regulated accounting, operating, maintenance and administration expense would have been higher by $1 million (2006 - $50 million).

Revenue difference deferral account (RDDA)

On March 30, 2007, the OEB issued a decision approving the establishment of the RDDA to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year. The new deferral account was to represent the revenue differential between existing and future rates for the period commencing January 1, 2007. On August 16, 2007, in its decision on Hydro One Networks' 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the RDDA liability, which will be returned to customers over the fourteen-month period ending December 31, 2008.

Retail settlement variance accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's *Accounting Procedures Handbook*. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The Company has accumulated a net liability in its RSVA since May 1, 2006 which was taken into consideration in the revenue requirement of Hydro One Networks as part of the 2008 distribution rate application filed with the OEB in December 2007.

Export and wheeling fees

Consistent with the IESO's Market Rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of these export and wheeling fees, plus interest, were taken into consideration in the revenue requirement of Hydro One's transmission business as part of the Company's transmission rate application filed with the OEB in September 2006. On August 16, 2007, the OEB issued its decision in respect of the Company's transmission rate application and approved final amounts and disposition treatments for the export wheeling fees. The export wheeling fees will be factored into rates over a four-year period ending December 31, 2010.

Transmission earnings sharing mechanism (ESM)

On February 21, 2006, the OEB issued a decision that established an ESM to equally share, between the Company's shareholder and ratepayers, any transmission earnings in excess of the approved rate of return of 9.88%, for the period January 1, 2006 until new transmission rates were set. Consequently, 50% of the Company's excess earnings were deferred as a regulatory liability. On March 30, 2007, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The ESM was taken into consideration in setting the revenue requirement of Hydro One Networks for 2007 and 2008. On August 16, 2007, in its decision on Hydro One Networks 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the ESM which will be returned to customers over a fourteen-month period ending December 31, 2008.

8. DEBT

December 31 (Canadian dollars in millions)	2007	2006
Short-term notes payable	-	60
Long-term debt:		
4.45% notes due 2007	-	282
4.55% notes due 2007	-	73
4.70% (2006 – 4.10%) notes due 2008[1]	40	40
4.00% notes due 2008	500	500
3.95% notes due 2009	400	400
7.15% debentures due 2010	400	400
6.40% notes due 2011	250	250
5.77% notes due 2012	600	600
4.64% notes due 2016	450	450
5.18% notes due 2017	300	-
7.35% debentures due 2030	400	400
6.93% notes due 2032	500	500
6.35% notes due 2034	385	385
5.36% notes due 2036	600	600
4.89% notes due 2037	400	-
6.59% notes due 2043	315	315
5.00% notes due 2046	75	75
	5,615	5,270
Less: Long-term debt payable within one year	(540)	(395)
Net unamortized premiums	13	9
Unamortized hedging losses[2]	-	(12)
Unamortized debt issuance costs	(25)	(24)
Long-term debt	5,063	4,848

[1] Step-up coupon from 4.10% to 6.40%, extendable to 2011.

[2] Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

Short-term debt represents promissory notes issued pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2007, the notes had a weighted-average interest rate of 5.7%.

Hydro One has a $750 million committed and unused revolving standby credit facility with a syndicate of banks maturing in August 2010. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company issues notes for long-term financing under the Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which $2,200 million is remaining and is currently available until July 2009.

The long-term debt is subject to covenants that, among other things, limit permissible debt as a percentage of total capitalization, limit ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2007, the Company was in compliance with these covenants.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in the following table:

Years to Maturity	Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)*	Weighted Average Interest Rate *(Percent)*
1 year	540	4.1
2 years	400	4.0
3 years	400	7.2
4 years	250	6.4
5 years	600	5.8
	2,190	5.3
6 – 10 years	750	4.9
Over 10 years	2,675	6.2
	5,615	5.7

9. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table:

December 31 (Canadian dollars in millions)	2007		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt[1]	5,615	6,005	5,270	5,831

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the step-up note, which is marked to market.

Hydro One may enter into derivative agreements, such as forward starting pay fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions are accounted for as cash flow hedges of anticipated transactions. In October 2007, upon issuance of debt under the Company's medium term note program, Hydro One terminated two forward interest rate swap agreements having a total notional principal amount of $200 million, resulting in a net gain of $0.4 million. The net gain was recorded as other comprehensive income and is being amortized to financing charges over the term of the related debt. In late 2007, Hydro One entered into two new forward starting pay fixed interest rate swap agreements with a notional amount of $140 million.

As at December 31, 2007, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance with an initial maturity date in 2007, and with extended maturity dates up to 2011. In 2006, the interest rate swap was accounted for as a fair value hedge. In 2007, the interest rate swap was accounted for using the fair value option without hedge accounting. This agreement has a notional principal amount of $40 million and a fair value of $nil (2006 - $nil).

The Company has no significant counter-party credit risk exposure as the fair value of the interest rate swap contracts was not significant in 2007 or in 2006.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2007, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a

significant amount of revenue from any single customer. As at December 31, 2007, there were no significant balances of accounts receivable due from any single customer.

The Company will continue to use derivative instruments to manage interest rate risk. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. Hydro One monitors and minimizes credit risk through various techniques including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties and entering into master agreements which enable net settlement.

10. EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2007 and 2006 was as follows:

	% of Plan Assets	
December 31	**2007**	**2006**
Equity securities	62.5	64.6
Debt securities	34.1	32.0
Other	3.4	3.4
	100.0	100.0

Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $90 million and $92 million at December 31, 2007 and 2006 respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario on September 20, 2007, effective for December 31, 2006, the Company contributed $95 million to its pension plan in respect of 2007 (2006 - $86 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009 and will depend on future investment returns, and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2007, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $137 million in 2007 (2006 - $122 million).

Year ended December 31 (Canadian dollars in millions)	Pension		Employee Future Benefits other than Pension	
	2007	**2006**	**2007**	**2006**
Change in accrued benefit obligation				
Accrued benefit obligation, January 1	5,411	5,355	1,100	1,143
Current service cost	105	106	23	33
Interest cost	282	267	57	58
Benefits paid	(264)	(253)	(42)	(36)
Plan amendments	-	6	-	22
Net actuarial gain	(457)	(70)	(44)	(120)
Accrued benefit obligation, December 31	5,077	5,411	1,094	1,100
Change in plan assets				
Fair value of plan assets, January 1	5,123	4,713	-	-
Actual return on plan assets	142	571	-	-
Benefits paid	(264)	(253)	-	-
Employer's contributions[1]	95	86	-	-
Employees' contributions	17	17	-	-
Administrative expenses	(13)	(11)	-	-
Fair value of plan assets, December 31	5,100	5,123	-	-
Funded status				
Funded excess (Unfunded benefit obligation)	23	(288)	(1,094)	(1,100)
Unamortized net actuarial losses	336	645	178	236
Unamortized past service costs	21	25	21	25
Deferred pension asset (accrued benefit liability)	380	382	(895)	(839)
Less: current portion	-	-	40	36
Deferred pension asset (long-term liability)	380	382	(855)	(803)

[1] In January, 2008, the Company made a contribution of $8 million in respect of 2007 (2007 - $8 million in respect of 2006).

Year ended December 31 (Canadian dollars in millions)	Pension 2007	Pension 2006	Employee Future Benefits other than Pension 2007	Employee Future Benefits other than Pension 2006
Components of net periodic benefit cost				
Current service cost, net of employee contributions	88	89	23	33
Interest cost	282	267	57	58
Actual return on plan asset net of expenses	(129)	(560)	-	-
Actuarial gain	(457)	(70)	(44)	(120)
Plan amendments	-	6	-	22
Other	-	(1)	-	(1)
Costs arising in the period	(216)	(269)	36	(8)
Differences between costs arising in the period and costs recognized in the period in respect of:				
Return on plan assets	(212)	248	-	-
Actuarial loss (gain)	522	177	59	149
Plan amendments	3	(3)	4	(19)
Net periodic benefit cost[2]	97	153	99	122
Charged to results of operations[2]	58	42	60	75
Effect of 1% increase in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	167	156
Service cost and interest cost	-	-	12	13
Effect of 1% decrease in health care cost trends on:				
Accrued benefit obligation, December 31	-	-	(132)	(124)
Service cost and interest cost	-	-	(9)	(10)
Significant assumptions				
For net periodic benefit cost:				
Expected rate of return on plan assets	6.75%	6.75%	-	-
Weighted-average discount rate	5.25%	5.00%	5.24%	4.98%
Rate of compensation scale escalation (without merit)	3.25%	3.25%	3.25%	3.25%
Rate of cost of living increase	2.50%	2.50%	2.50%	2.50%
Average remaining service life of employees *(years)*	10	10	9	10
Rate of increase in health care cost trend[3]	-	-	4.40%	4.40%
For accrued benefit obligation, December 31:				
Weighted-average discount rate	5.50%	5.25%	5.50%	5.24%
Rate of compensation scale escalation (without merit)	3.00%	3.25%	3.00%	3.25%
Rate of cost of living increase	2.25%	2.50%	2.25%	2.50%
Rate of increase in health care cost trend[3]	-	-	4.40%	4.40%

[2] The Company follows the cash basis of accounting. During 2007, pension costs of $95 million (2006 - $86 million) were attributed to labour, of which $58 million (2006 - $42 million) was charged to operations, $37 million (2006 - $34 million) was capitalized as part of the cost of fixed assets, and $nil (2006- $10 million) was attributed to a regulatory asset.

[3] 8.69% in 2007 grading down to 4.40% per annum in and after 2018 (2006 – 7.87% in 2006 grading down to 4.40% per annum in and after 2014).

[4] 8.33% in 2008 grading down to 4.40% per annum in and after 2018 (2006 – 8.69% in 2007 grading down to 4.40% per annum in and after 2014).

11. ENVIRONMENTAL LIABILITIES

December 31 (Canadian dollars in millions)	2007	2006
Environmental liabilities, January 1	70	79
Interest accretion	4	5
Expenditures	(12)	(17)
Revaluation adjustment	3	3
Environmental liabilities, December 31	65	70
Less: current portion	(13)	(15)
	52	55

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 - $13 million; 2009 - $12 million; 2010 - $10 million; 2011 - $8 million; 2012 - $6 million and thereafter - $35 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

12. SHARE CAPITAL

Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2007, preferred dividends in the amount of $18 million (2006 - $18 million) and common dividends in the amount of $307 million (2006 - $332 million) were declared.

Earnings per Share

Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted-average number of common shares outstanding during the year.

13. RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO, OPA and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2007 includes $1,203 million (2006 - $1,206 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2007 includes $127 million (2006 - $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2007 includes $21 million (2006 - $21 million) related to these services.

In 2007, Hydro One purchased power in the amount of $2,213 million (2006 - $2,183 million) from the IESO administered electricity market and $27 million (2006 - $38 million) from OPG.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2007, Hydro One incurred $10 million (2006 - $9 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $12 million (2006 - $15 million), primarily for the transmission business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2007 and 2006.

Consistent with the OPA mandate, the OPA is responsible for some of our CDM programs. The funding includes program costs, incentives and management fees and bonuses. In 2007, Hydro One received $3 million (2006 – $nil) from the OPA in respect of the CDM programs and had a net accounts receivable of $3 million (2006 – $nil).

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (Canadian dollars in millions)	2007	2006
Accounts receivable	97	114
Accounts payable and accrued charges	(234)	(230)

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $202 million (2006 - $195 million).

14. CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Balance Sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (Canadian dollars in millions)	2007	2006
Accounts receivable decrease (increase)	18	(149)
Materials and supplies increase	(11)	-
Accounts payable and accrued charges increase (decrease)	70	(39)
Accrued interest increase	6	6
Long-term accounts payable and accrued charges decrease	(3)	(7)
Employee future benefits other than pension increase	52	87
Other	3	(4)
	135	(106)
Supplementary information:		
Interest paid	306	302
Payments in lieu of corporate income taxes	230	252

15. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century, Ontario Hydro has erected dams, generating stations and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act, 1998*. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which Hydro One acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). Currently, the OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, it anticipates having to pay more than the approximately $900,000 per year

than it currently is paying to these Indian bands and bodies. If the Company cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if it is not able to recover them in future rate orders.

Draft PCB regulations

Future changes in environmental regulations may result in material changes to the Company's estimated liability related to the management of PCBs. On November 4, 2006, Environment Canada published new draft regulations governing the management of PCBs. These draft regulations may be finalized in 2008. The Company has estimated its operating expenditures for complying with these draft regulations to be between $250 million and $375 million in excess of amounts already recorded as environmental liabilities on its Balance Sheet. If required, most of these additional expenditures are expected to be incurred between 2013 and 2025. No obligation has been recorded in the financial statements for these increased expenditures due to continued uncertainty regarding the timing and content of the final regulations. In the event that an obligation related to new regulations is recorded, the Company expects to simultaneously record a regulatory asset of equivalent value.

16. COMMITMENTS

Agreement with Inergi

Effective March 1, 2002, Cap Gemini Canada Inc. began providing services to Hydro One through Inergi. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a ten-year period. The initial service level price ranged between $90 million and $130 million per year, subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2007, and in total thereafter are as follows: 2008 - $100 million, 2009 - $97 million; 2010 - $93 million; 2011 - $90 million; 2012 - $16 million and thereafter - $nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the parental guarantee. As at December 31, 2007, the Company provided prudential support using only parental guarantees, reflecting a change from 2006. If Hydro One's highest long term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support. Prudential support at December 31, 2007 was provided using bank letters of credit of $nil million (2006 - $22 million) and parental guarantees of $325 million (2006 - $275 million).

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2007, Hydro One had bank letters of credit of $95 million (2006 - $93 million) outstanding relating to retirement compensation arrangements.

Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2007 and in total thereafter are as follows: 2008 - $6 million; 2009 - $5 million; 2010 - $2 million; 2011 - $1 million; 2012 - $1 million and thereafter - $1 million.

17. SEGMENT REPORTING

Hydro One has three reportable segments:

- The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The distribution business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

Year ended December 31 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2007				
Segment profit				
Revenues	1,242	3,382	31	4,655
Purchased power	-	2,240	-	2,240
Operation, maintenance and administration	415	549	31	995
Depreciation and amortization	242	273	6	521
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	585	320	(6)	899
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				604
Capital expenditures	560	511	20	1,091
2006				
Segment profit				
Revenues	1,245	3,273	27	4,545
Purchased power	-	2,221	-	2,221
Operation, maintenance and administration	390	460	30	880
Depreciation and amortization	241	269	5	515
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	614	323	(8)	929
Financing charges				295
Income before provision for payments in lieu of corporate income taxes				634
Capital expenditures	402	417	4	823

December 31 (Canadian dollars in millions)	2007	2006
Total assets		
Transmission	7,273	6,950
Distribution	5,411	5,161
Other	106	99
	12,790	12,210

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

18. SUBSEQUENT EVENTS

On January 21, 2008, the Company entered into a forward starting pay fixed interest rate swap agreement to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. This transaction had a notional amount of $60 million and is used to lock in the interest rate of a forecasted debt issuance planned for later in 2008. This transaction is being accounted for as a cash flow hedge of a forecasted transaction.

On January 28, 2008 the Company increased its committed revolving credit facility, which supports its commercial paper program, by $250 million to $1,000 million. The maturity date remains unchanged at August 10, 2010.

19. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2007 Consolidated Financial Statements.

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Year ended December 31 (Canadian dollars in millions)	2007	2006	2005	2004	2003
Statement of operations data					
Revenues					
Transmission	1,242	1,245	1,310	1,262	1,298
Distribution	3,382	3,273	3,085	2,874	2,734
Other	31	27	21	17	26
	4,655	4,545	4,416	4,153	4,058
Costs					
Purchased power	2,240	2,221	2,131	1,987	1,872
Operation, maintenance and administration	995	880	792	771	795
Depreciation and amortization	521	515	487	480	454
	3,756	3,616	3,410	3,238	3,121
Regulatory recovery[1]	-	-	-	91	-
Income before financing charges and provision for payments in lieu of corporate income taxes	899	929	1,006	1,006	937
Financing charges	295	295	325	331	348
Income before provision for payments in lieu of corporate income taxes	604	634	681	675	589
Provision for payments in lieu of corporate income taxes	205	179	198	177	193
Net income	399	455	483	498	396
Basic and fully diluted earnings per common share *(Canadian dollars)*	3.809	4.366	4.652	4.798	3.779
December 31 (Canadian dollars in millions)					
Balance sheet data					
Assets					
Transmission	7,273	6,950	6,813	6,771	6,576
Distribution	5,411	5,161	4,893	4,836	4,614
Other	106	99	92	95	94
Total assets	12,790	12,210	11,798	11,702	11,284
Liabilities					
Current liabilities (including current portion of long-term debt)	1,452	1,194	1,341	1,262	1,192
Long-term debt	5,063	4,848	4,443	4,590	4,517
Other long-term liabilities	1,389	1,347	1,298	1,326	1,284
Shareholder's equity					
Share capital	3,637	3,637	3,637	3,637	3,637
Retained earnings	1,258	1,184	1,079	887	654
Accumulated Other Comprehensive Income	(9)	-	-	-	-
Total liabilities and shareholder's equity	12,790	12,210	11,798	11,702	11,284

HYDRO ONE INC.
FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS (continued)

Year ended December 31 (Canadian dollars in millions)	2007	2006	2005	2004	2003
Other financial data					
Capital expenditures					
Transmission	560	402	349	432	289
Distribution	511	417	338	288	292
Other	20	4	4	7	16
Total capital expenditures	1,091	823	691	727	597
Ratios					
Net asset coverage on long-term debt[2]	1.87	1.92	1.93	1.88	1.86
Earnings coverage ratio[3]	2.67	2.67	2.69	2.70	2.43
Operating statistics					
Transmission					
Units transmitted *(TWh)*[4]	152.2	151.1	157.0	153.4	151.7
Ontario 20-minute system peak demand *(MW)*[4]	25,809	27,056	26,219	25,204	24,849
Ontario 60-minute system peak demand *(MW)*[4]	25,737	27,005	26,160	24,979	24,753
Total transmission lines *(circuit-kilometres)*	28,915	28,600	28,547	28,643	28,621
Distribution					
Units distributed to Hydro One customers *(TWh)*[4]	30.2	29.0	29.7	28.5	27.9
Units distributed through Hydro One lines *(TWh)*[4,5]	45.7	44.7	45.6	44.8	44.7
Total distribution lines *(circuit-kilometres)*	122,933	122,460	122,118	121,736	121,285
Customers	1,311,714	1,293,396	1,273,768	1,258,925	1,238,748
Total regular employees	4,602	4,295	4,189	4,118	3,967

[1] As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004 the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act, 2002*, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

[2] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[4] System related statistics include preliminary figures for December.

[5] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.